ACCESSION #: 9208240063
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Nine Mile Point Unit 2 PAGE: 1 OF 23

DOCKET NUMBER: 05000410

TITLE: Transformer Fault Causes Reactor Scram and Uninterruptible Power Supply Failure Causes Loss of Annunciation Which Led to Declaration of a Site Area Emergency
EVENT DATE: 08/13/91 LER #: 91-017-01 REPORT DATE: 08/13/92

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(i), 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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Engineering NMP2

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: EL COMPONENT: XFM MANUFACTURER: M175
B EE UJX E353

REPORTABLE NPRDS: N

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

At 0548 hours on August 13, 1991, Nine Mile Point Unit 2 (NMP2) experienced a turbine trip and reactor scram when the "B" Phase Main Transformer developed an internal fault. The transformer fault created an electrical disturbance throughout the normal electrical distribution system, resulting in the loss of five non-safety related Uninterruptible Power Supplies (UPS). As a result, the Control Room lost annunciation and most Balance of Plant (BOP) instrumentation. The conditions described in this report mandated entry into a Site Area Emergency as specified by the Site Emergency Plan. Prior to the event, NMP2 was in operational condition 1 (RUN) at 100% rated thermal power.

The cause of the transformer fault was a failure of the coil insulation.

Due to the magnitude of the failure, the root cause could not be positively determined, however, the proximate cause was a manufacturer's defect.

Control Room operators verified the reactor scram, identified and re-energized the failed UPS's, identified the cause of the reactor scram, and cooled down the reactor to terminate the emergency event. Other corrective actions included: 1) replacing the "B" phase transformer with the installed spare; 2) modifying the UPS's; 3) replacement of back-up batteries in the UPS's; 4) developing a back-up battery replacement schedule; and 5) revision of the Reactor Water Cleanup Operating Procedure.

END OF ABSTRACT

I. DESCRIPTION OF EVENT

At 0548 hours on August 13, 1991, Nine Mile Point Unit 2 (NMP2) experienced a turbine trip and reactor scram when the "B" Phase Main Transformer developed an internal fault. The transformer fault also created an electrical disturbance throughout the normal electrical distribution system. This electrical disturbance resulted in the loss of five non-safety related Uninterruptible Power Supplies (UPS). As a result, the Control Room lost most Balance of Plant (BOP) instrumentation and all annunciation which created several conflicting indications of reactor status. The conditions described in this report mandated entry into a Site Area Emergency as specified by the Emergency Plan.

Prior to the event, NMP2 was in operational condition 1 (RUN) at 100 percent rated thermal power. The following Feedwater System (FWS) and Condensate System (CNM) pumps were running at the time of the event: Feedwater pumps 2FWS-P1B and P1C; Condensate Booster pumps 2CNM-P2A and P2B; and Condensate Pumps 2CNM-P1A, P1B, and P1C. Residual Heat Removal System (RHR) Loops "B" and "C" (also serve as Low Pressure Coolant Injection) were removed from service for scheduled maintenance on various valves and instruments. Several Technical Specification (T.S.) Limiting Conditions for Operation (LCO's) were entered for various liquid process effluent monitors. Aside from the LCO's and the RHR outage, plant operating conditions were normal.

The following sequence of events is a reconstruction of the events which occurred. Due to the loss of UPS power, the normal means of recording events of this nature were initially unavailable (process computer, recorders, and alarm typer). Control Room meters and recorders, powered from the affected UPSs, were inoperable during the first thirty four minutes of the event. The plant process computer was unavailable an additional forty nine minutes. This sequence of events is based on operator interviews and written statements, operator logs, Post Accident Monitoring (PAM) recorded plots and operating crew debriefs.

After evaluation of plant conditions following the transient, the Station Shift Supervisor (SSS) ordered the reactor mode switch be placed in the SHUTDOWN position and commenced responding to plant conditions. The Control Room operators recognized that the two operating Reactor Feedwater pumps had tripped and manually initiated the Reactor Core isolation Cooling System (ICS) to control decreasing reactor water level.

Reactor systems responded to the turbine trip as expected. At 1050 pounds per square inch gauge (psig) reactor pressure, the PAM recorders shifted to fast speed and continued to provide reactor pressure and water level indication throughout the event, and an Alternate Rod Insertion (ARI) was initiated. Two Main Steam System (MSS) Safety Relief Valves (SRVs) lifted to limit reactor pressure to 1070 psig. The Emergency Operating Procedures were entered when entry conditions were met for decreasing reactor water level.

0548 hours

o The main turbine tripped as a result of an internal fault in the "B" Phase Main Transformer.

o Turbine Stop Valve (TSV) closure and Turbine Control Valve (TCV) fast closure signals resulted in a reactor scram and Reactor Recirculation pump downshift to slow speed due to the End-Of-Cycle Recirculation Pump Trip (EOC-RPT) signal.

o Turbine Bypass Valves opened to control reactor pressure.

I. DESCRIPTION OF EVENT (cont.)

o Normal station power fast transferred to reserve power.

o Uninterruptible Power Supplies (2VBB-UPS 1A-1D, 1G) failed to provide power to their respective loads resulting in:

o Loss of the plant Radio Communication System (Radiax).

o Loss of Control Room annunciators.

o Cooling Tower bypass valves opened on loss of power to temperature monitoring instrumentation (valve motive power is from station reserve power).

o Loss of Plant Process Computer (PCS), Safety Parameter Display System (SPDS), Emergency Response Facility (ERF) computer, General Electric Transient Analysis Recording System (GETARS), Gaseous Effluent Monitoring System (GEMS) computer, 3D-Monicore computer, and the Digital Radiation Monitoring System (DRMS) computer.

o Loss of plant Gaitronics communication and paging system.

o Partial loss of the plant telephone system.

o Loss of Balance of Plant (BOP) instrumentation.

o Loss of Essential Lighting (normal system lighting remained operational).

o Non-safety related Control Room recorders failed as is.

o Reactor Feedwater level control valves locked up in the open position.

o Loss of Drywell cooling (unit cooler fans only).

o Loss of Control Rod Position indication.

o Condensate Booster Pump and Reactor Feedwater pump minimum flow valves failed open.

o At 1037 psig a reactor scram signal was generated by the Reactor Protection System (RPS) logic on high reactor vessel pressure.

o At 1050 psig an ARI signal was initiated, and the PAM recorders switched to fast speed.

o At 1070 psig, two MSS, SRV's, 2MSS*PSV128 and 2MSS*PSV133, lifted for approximately 30 seconds.

I. DESCRIPTION OF EVENT (cont.)

o Condensate Booster Pump 2CNM-P2A tripped on low suction pressure and pump 2CNM-P2C automatically started.

o The two operating Reactor Feedwater pumps tripped on low suction pressure.

o The Division II Primary Containment Hydrogen/ Oxygen sample pump tripped spuriously.

The Control Room operators made the following observations indicating that an automatic reactor scram had occurred:

o Scram pilot lights were extinguished.

o Average Power Range Monitor (APRM) Meters on Control Room auxiliary panels were operable and indicating downscale (with front panel recorders failed at 100%).

0549 hours

o Reactor mode switch was placed in the "SHUTDOWN" position on orders from the SSS. This was a conservative action which would have generated a reactor scram if an automatic reactor scram had not yet occurred.

o Scram Discharge Volumes were indicating full on Control Room auxiliary panels.

0555 hours

o In order to maintain reactor water level without Reactor Feedwater pumps operating, ICS was manually initiated. The ICS turbine experienced flow, speed, and pressure oscillations while in automatic and was transferred to manual control. Subsequently the ICS turbine performance parameters stabilized.

o Reactor Recirculation flow control valves experienced an automatic runback at reactor water Level 4 (178.3 inches) as designed.

0556 hours

o At reactor water Level 3 (159.3 inches), a scram signal was generated by RPS on low vessel water level. Additionally, the RHR sample and discharge to radwaste containment isolation valves (Group 4) isolated.

o Emergency Operating Procedure N2-EOP-RPV, "RPV Control" was entered due to lowering reactor water level (159.3 inches and decreasing). Additionally, Control Room operators entered Emergency Operating Procedure N2-EOP-C5, "Level/Power Control" due to the lack of control rod position indication. Per N2-EOP-C5, the Automatic Depressurization System (ADS) was manually inhibited to prevent automatic initiation.

I. DESCRIPTION OF EVENT (cont.)

o RHR train A was placed in suppression pool cooling to support ICS operation.

0600 hours

o Due to loss of Control Room annunciation with a plant transient in progress, the SSS assumed the role of Site Emergency Director (SED) and declared a Site Area Emergency in accordance with Site Emergency Action Procedure S-EAP-2, "Classification of Emergency Conditions".

o Operators were dispatched to investigate UPS operation.

0608 hours

o State and local authorities were notified of the Emergency declaration.

0612 hours

o Nuclear Regulatory Commission was notified via the Emergency Notification System.

0614 hours

o ICS injection to the reactor was secured and the system realigned to full flow test (condensate storage tank to condensate storage tank).

This line up leaves the ICS pump readily available for injection.

0615 hours

o Reactor vessel water level reached Level 8 (202.3 inches).

o The Condensate Booster pumps were secured to limit the reactor vessel cooldown rate and to control reactor water level.

o Plant operators reported that 2VBB-UPS 1A through 1D and 1G had tripped.

0620 hours

o Condensate pumps 2CNM-P1B and P1C were secured (2CNM-P1A remained in service). Reactor vessel water level began to decrease and reactor pressure stabilized.

0622 hours

o The SSS directed restoration of 2VBB-UPS1 A through 1 D and 1G by manually transferring to the maintenance bus power source. As a result, Control Room annunciators and other indications were restored.

I. DESCRIPTION OF EVENT (cont.)

o A Group 9 Primary Containment isolation occurred (Primary Containment Purge and Vent System [CPS] valves). The isolation occurred when power was restored to the isolation logic before the Standby Gas Treatment (GTS) radiation monitor power was restored.

0630 hours

o The full core display, when restored, indicated that all rods were fully inserted except six which had no indication. Operators also observed that one rod had no indication on the Rod Worth Minimizer (RWM) and that 15 rods were without indication on the Rod Sequence Control System (RSCS).

o Drywell unit cooler fans were restored. The highest individual Drywell temperature recorded was 165 degrees Fahrenheit. The highest average Drywell temperature remained below 150 degrees Fahrenheit.

0640 hours

o Condensate Booster Pump 2CNM-P2A was started to maintain reactor water level within a band of 165 inches to 180 inches. Control Room operators attempted to open the Reactor Feedwater pump suction valves 2CNM-MOV84A and B without equalizing the pressure across the valve (at SSS direction due to unknown radiological conditions in the Turbine Building). The valves would not open precluding flow to the reactor. As a result, reactor water level decreased to Level 3 (159.3 inches) and operators re-entered Emergency Operating Procedure N2-EOP-RPV. Operators subsequently used the Reactor Feedwater pump bypass valve 2CNM-LV137 to control reactor vessel water level.

0650 hours

o Jumpers were installed to bypass the RPS interlocks per Emergency Operating Procedure N2-EOP-6, "NMP2 EOP Support Procedure", attachment 14, to reset the reactor scram with a scram signal still present. This action was performed to permit, draining the scram discharge volume and performing additional scrams to insert control rods had it been required.

0653 hours

o The scram was reset per Emergency Operating Procedure N2-EOP-RPV section RO, "Power Control".

o All rods indicated full in. The SSS directed exit from Emergency Operating Procedure N2-EOP-C5. Reactor pressure was controlled using the turbine bypass valves.

0700 hours

o Commenced manual monitoring of various plant effluents due to the loss of DRMS and GEMS computers.

0711 hours

o Plant process computer was restored.

o Restarted the Division II Primary Containment Hydrogen/Oxygen sample pump.

0729 hours

o Started mechanical air removal pumps to maintain condenser vacuum (reactor pressure was being controlled using the turbine bypass valves).

0738 hours

o Condensate pump 2CNM-P1B was started due to a high stator temperature on the operating Condensate pump 2CNM-P1A.

o The Technical Support Center was activated.

0740 hours

o ICS was secured to reduce the cooldown rate.

0750 hours

o The Safety Parameter Display System was restored.

0804 hours

o The Emergency Operating Facility was activated

0805 hours

o A stack GEMS computer reboot was initiated to re-establish Control Room indication.

0806 hours

o Reactor Recirculation System flow control valves were fully opened.

0810 hours

o RHR loops B and C were returned to operable status.

I. DESCRIPTION OF EVENT (cont.)

0821 hours

o The ADS inhibit was removed, returning the system to automatic, and the jumpers were removed, restoring RPS interlocks.

0834 hours

o Verified that no adverse radiological conditions existed on site.

0847 hours

o The Stack GEMS computer was declared operable.

0857 hours

o Initial reports from Offsite Radiological Assessment Teams indicated readings were normal at background levels.

0937 hours

o ICS outboard containment isolation check valve 21CS*AOV156 did not indicate fully closed. Operators de-energized the motor operated injection shutoff valve 21CS*MOV126 shut per Technical Specifications and declared ICS inoperable. (ICS was not required at this time for reactor water level control).

0950 hours

o 2VBB-UPS 1C & 1D were restored to their normal power sources. 2VBB-UPS 1A & 1B could not be transferred to their normal power supply; therefore, they were left on their maintenance supply.

1000 hours

o The Control Room operators determined that two SRVs had lifted at the beginning of the event (0548 hours). Operations Surveillance Procedure N2-OSP-ISC-M@002, "Drywell Vacuum Breaker Operability Test", which is a test required by Technical Specifications following a lift of SRV's, was initiated by 1006 hours.

1020 hours

o 2VBB-UPS 1G was restored to its normal power supply.

1031 hours

o The Group 9 isolation was reset.

1055 hours

o Reactor Water Cleanup System (WCS) pump 2WCS-P1B was started and the system lined up to purify and reject reactor water to the condenser hotwell. This action was performed to maintain reactor water chemistry and reduce reactor water level.

1056 hours

o WCS isolated (Group 6 and 7 isolation) due to a high Delta Flow signal, tripping pump 2WCS-P1B.

1151 hours

o Operations Surveillance Procedure N2-OSP-ISC-M@002, "Drywell Vacuum Breaker Operability Test", was completed.

1158 hours

o RHR loop "A" was secured from the suppression pool cooling mode and pump 2RHS*P1A was secured.

1217 hours

o Group 4 isolation, RHR sample and discharge to radwaste isolation valves, was reset.

o Group 5 isolation, shutdown cooling isolation valves, was reset to establish shutdown cooling lineup (this isolation signal is present when reactor pressure is above 128 psig).

o Group 6 and 7 isolations, WCS inboard and outboard isolation valves, were reset.

1415 hours

o Condensate demineralizer bypass valve 2CNM-AOV109 was closed to minimize reactor water chemistry concerns.

1458 hours

o Reactor Recirculation pump 2RCS*P1B was secured to prepare for initiating shutdown cooling.

I. DESCRIPTION OF EVENT (cont.)

1508 hours

o Residual Heat Removal pump 2RHS*P1B was started in the shutdown cooling mode.

1519 hours

o Condensate Booster pump 2CNM-P2A was secured per the normal shutdown Operating Procedure, N2-OP-101C, "Plant Shutdown".

1520 hours

o Condensate pump 2CNM-P1A was secured.

1846 hours

o Reactor water temperature dropped below 200 degrees Fahrenheit. Cold Shutdown condition (Mode 4) was established.

1943 hours

o SED terminates the Site Area Emergency.

II. CAUSE OF EVENT

Transformer Fault

The initiating event discussed in this LER is the failure of the "B" Phase Main Generator Step-up Transformer (2MTX-XM1B - see illustration page 21) which developed an internal fault. The internal fault was a winding-to-winding short due to failed insulation in one of three low voltage coils. The "B" Phase transformer differential and the overall unit differential relays activated to isolate the fault by disconnecting the main generator from the 345 KV line. This resulted in a turbine trip assuring reactor scram from Turbine Control Valve fast closure/Turbine Stop Valve closure.

The transformer was shipped to the Magnetek Repair Facility in Bradenton, Florida. There, the transformer was carefully dismantled and all the internals analyzed to determine the root cause of the failure. The results of this analysis were reported in a meeting between Niagara Mohawk and the Nuclear Regulatory Commission on May 1 9, 1992. Below is a summary of those results.

As the transformer coils were unstacked, damage was observed on high voltage coil 10. This was postulated to be a failure from low voltage coil 5 to high voltage coil 10 near the end of the event when the dielectric strength between the high and low voltage coils was decreased.

The reduced

II. CAUSE OF EVENT (cont.)

dielectric strength was caused by the expansion of low voltage coil 5 and gases (from the insulating oil) rising to the top of the transformer. This damage was superficial and a result of the event, not a cause for it.

The most damage, both electrical and mechanical, occurred in low voltage coils 5 and 6. Multiple turn-to-turn and coil-to-coil failures occurred in two major areas of these two coils. Whatever caused the failures was destroyed along with the windings during the failure of these coils.

Several external causes were ruled out by the investigation. There was no sign of static electrification,), high velocity oil flow tracking of the oil spacers, core steel overheating, nor geomagnetically induced currents. Maintenance records were analyzed for possible causes or indications related to the failure. The transformer was properly maintained to the manufacturers recommendations and oil samples showed no signs of the impending failure.

No evidence of the cause for the transformer insulation failure could be found. However, the external causes and improper maintenance were ruled out. Therefore, the proximate cause appears to be a defect in the manufacture of the transformer.

UPS Failure

Subsequent to the internal fault which occurred on the main step up transformer, five Exide UPS's (2VBB-UPS 1A, 1B, 1C, 1D, and 1G - see illustration page 22) tripped resulting in loss of power to their respective loads. A root cause evaluation has been completed in accordance with Nuclear Division Procedure NDP-16.01, "Root Cause Evaluation".

Extensive analysis and testing has concluded that all five Exide UPS units shutdown as a result of a logic initiated trip. The failure of the "B" Phase Main Transformer caused a voltage drop on the maintenance power supply to all five UPS units. The degraded voltage on the maintenance power supply caused the voltage on the UPS logic power supply to decrease below its trip setpoint, causing the units to trip. Concurrently, the automatic load transfer to the maintenance supply was prevented by design due to the degraded voltage conditions on the maintenance power supply.

The root cause for the simultaneous tripping of the five UPS units is improper design. The UPS is not designed to accommodate a degraded voltage condition of the maintenance power supply. The following design factors allowed the UPS logic power supply voltage to decrease below its trip setpoint as a result of the "B" Phase Main Step-up Transformer fault.

o The logic power supply is normally energized from the maintenance power supply with the inverter output as a backup versus inverter preferred.

o Under degraded voltage conditions, the logic power supply switching circuit does not actuate until the supply voltage has decreased to well below the level that will cause the logic to trip.

Although degraded batteries (internal to the UPS units) were discovered during the course of this evaluation, it was concluded that this condition was not the cause of the simultaneous tripping of the five UPS units. However, fully charged batteries may have prevented the tripping of the units even though that is not part of their design basis.

Reactor Scram

A reactor scram occurred as a result of a main turbine trip (Turbine Control Valve fast closure/Turbine Stop Valve closure) initiated from the "B" Phase Main Generator Step-up Transformer fault. This is an expected function through the generator protective relay scheme. A turbine trip and subsequent reactor scram is an expected response and consistent with station design when reactor power is above 30 percent of rated.

Group 4 Containment isolation

Subsequent to the reactor scram, the Residual Heat Removal System sample and discharge to Radwaste valves isolated when reactor water level reached Level 3 (159.3 inches).

The Group 4 isolation is an expected response to reactor water level dropping below 159.3 inches. Decreasing water level is a normal function of a reactor scram from full power (reactor vessel water level shrinks due to a rapid reduction in reactor steam flow), coupled with a loss of Reactor Feedwater flow. All systems functioned as required.

Group 6-7 Isolation

The root cause investigation into the WCS high differential flow isolation was performed utilizing Nuclear Division Procedure NDP-16.01, "Root Cause Evaluation". The root cause has been determined to be procedural inadequacy. Specifically, Operating Procedure N2-OP-37, Rev. 3, "Reactor Water Cleanup System", Section E.4.0 had instructional steps in the wrong sequence. in this section the WCS is started from no pumps in operation to one pump running, one filter/demineralizer in service, with all system flow directed to either the Liquid Radwaste System or to the main condenser. This section also delineates steps to be performed if venting of this system is required.

After reviewing N2-OP-37 and ascertaining the pump casing temperature was within 100 degrees Fahrenheit of reactor water temperature, the Control Room operator determined the appropriate procedural step to use. He then instructed a plant operator to shut the WCS pump discharge valve to aid in the system venting evolution. This action isolated the piping downstream of the pump from reactor pressure. The Control Room operator then aligned this piping to the main condenser, which was at a vacuum. The Control Room operator started the WCS pump and opened the reject flow control valve 2WCS-FV135, exposing the pump discharge piping to condenser vacuum. This caused the hot water in the pump discharge piping to flash to steam, resulting in the reject flow transmitter sensing line flashing and a very low (zero) reject flow signal. When the plant operator began to open the pump discharge valve and WCS inlet flow rose to over 150 gallons per minute, the high differential

flow timers initiated (inlet flow signal > 150 gallons per minute and reject flow signal at 0 gallons per minute). The Control Room operator attempted to reduce system flow but the 45 second timer elapsed and the high differential flow isolation occurred. If the procedure had left 2WCS-FV135 shut until the system venting was complete, the isolation would not have occurred.

Group 9 Isolation

When the UPS failure occurred, GTS Effluent Monitor 2GTS-RE105 defaulted to a de-energized state; however, the trip relay was also de-energized, preventing the isolation signal. When power was restored, the GTS high radiation level trip logic sensed the tripped condition of 2GTS-RE105 and initiated a Group 9 containment isolation. This condition occurred

consistent with station design where a tripped condition at 2GTS-RE105 conservatively results in a containment isolation. The root cause of the isolation has been determined to be the loss of UPS1A and UPS1B.

Technical Specification Concerns

During the Site Area Emergency, two Technical Specification (T.S.) requirements were not adhered to. Specifically, T.S. surveillance 4.6.4.b.1, requiring the drywell vacuum breakers by cycled within two hours of any SRV discharging steam to the suppression pool and T.S. Section 3.3.1 Action Statement b. This Action Statement required the reactor mode switch be locked in the "SHUTDOWN" position and one logic channel of RPS be placed in the tripped condition within one hour of removing both logic channels of RPS from service with the RPS jumpers.

The root cause investigation has determined that T.S. 4.6.4.b.1 surveillance was missed as a result of Operations personnel not identifying that SRVs had actuated until approximately four hours after initiation of the Site Area Emergency. At that point the required surveillance was successfully completed in the following two hours. The SRVs were open for a very short period of time during the initial moments of the event. Without the normal annunciation nor indication, the Control Room Operators were not aware that the SRVs had opened. Also, the reactor pressure indication on the Post Accident Monitoring (PAM) strip chart recorder was quickly obscured. During the event, the recorder automatically shifted to fast speed and the pressure spike was rolled up on the take-up spool in minutes. The complexity of the event precluded a review of the event via available strip charts until plant conditions were stabilized. At that time, the Operators reviewed the PAM strip chart, determined that SRV's had lifted, and took the appropriate actions required by Technical Specifications.

The cause for non-adherence to T.S. 3.3.1 Action Statement b was determined to be unusual plant conditions. This T.S. Action requirement specifies locking the mode switch in "SHUTDOWN", and placing at least one RPS trip system in a tripped condition within one hour. However, Operators following the EOP Support Procedure, N2-EOP-6, Attachment 14, defeated all the RPS interlocks

II. CAUSE OF EVENT (cont.)

(except for the manual scram) for a period of one and one half hours. During this time, the mode switch was in the "SHUTDOWN" position but not locked, and neither trip system was placed in the tripped condition. Defeating the RPS interlocks was required to reset the scram signal allowing a second scram to be initiated in an attempt to ensure all control rods were inserted. Without control rod position indication, the symptom based EOPs require inserting control rods via defeating t e RPS interlocks and inserting subsequent reactor scrams. The bases and safety evaluation for the EOP recognize the potential for this condition.

III. ANALYSIS OF EVENT

The following conditions are reportable in accordance with 10CFR50.73 (a)(2)(iv), "Any event or condition that resulted in manual or automatic activation of any Engineered Safety Feature (ESF), including the Reactor Protection System (RPS)":

o Automatic reactor scram.

o Group 6 and 7 (WCS) Primary Containment isolation.

o Group 9 (Primary Containment vent and purge) Primary Containment isolation.

o Group 4 (RHR sample and radwaste discharge) Primary Containment isolation.

The remaining conditions are reportable in accordance with 10CFR50.73 (a)(2)(i)(B), "Any operation or condition prohibited by the plant's Technical Specifications":

o Missed Technical Specification surveillance - 4.6.4 b.1.

o Deviation from Technical Specifications section 3.3.1 ACTION statement b and Table 3.3.1-1 ACTION statement 2, during implementation of the Emergency Operating Procedures.

ESF Actuations

The reactor scram occurred as designed. When the turbine tripped on generator protective relaying, an automatic reactor scram occurred to counter the positive reactivity added by the pressure excursion. Therefore, the automatic reactor scram occurred in accordance with the system design described in the Updated Safety Analysis Report (USAR).

A Reactor Water Cleanup isolation occurred at 1056 hours. The WCS isolation (Groups 6 and 7) is an ESF function of the Primary Containment and Reactor Vessel isolation Control System. Even though the WCS is classified as a primary power generation system, the inboard and outboard isolation

III. ANALYSIS OF EVENT (cont.)

valves are included in the Primary Containment isolation System, which is designed to protect against a radioactive release to the environment during accidents involving reactor coolant pressure boundary breaches. The differential flow measurement method (flow into the WCS compared to flow out of the WCS) is used to detect system leakage and provide a system isolation signal. The WCS isolation was a conservative action and did not impair the station's ability to achieve a safe shutdown condition, nor was there any impact to plant personnel or public safety stemming from the isolation.

A Group 9 Primary Containment isolation signal occurred at 0622 hours when power was restored to the UPS System. No actual valve movement occurred due to the purge and vent valves already being shut. Even though no high radiation level trip would have occurred, two other trip signals (low reactor water level and high drywell pressure) remained operable on loss of UPS power. When UPS power was initially lost, power was interrupted at 2GTS-RE105 which resulted in the radiation element defaulting to a de-energized state. Power was subsequently restored to the trip logic prior to restoring power to the radiation element, and the Group 9 trip logic initiated upon sensing 2GTS-RE105 in a de-energized state. A Group 9 isolation is a conservative action and had no impact on the course of the event.

The RHR sample and radwaste discharge valves (Group 4) isolation signal was generated when reactor vessel water level dropped below Level 3 (1 59.3 inches) at 0556 hours. The lowering reactor vessel water level could indicate a breach in the Reactor Coolant Pressure Boundary, therefore, these valves receive a shut signal attempting to isolate the leak, conserve reactor coolant, and limit the escape of radioactive materials from the Primary Containment. in this event, the low water level occurred due to level shrink on a scram from high reactor power with a loss of Feedwater, therefore the Group 4 isolation was a conservative action.

Technical Specification Issues

As a function of the turbine trip and reactor scram at 0548 hours, two reactor vessel safety relief valves, 2MSS*PSV128 and 2MSS*PSV133, lifted discharging steam into the suppression pool. NMP2 Technical Specification section 3.6.4 requires that drywell vacuum breakers be cycled within two hours it was not discovered that safety relief valves had lifted until 1000 hours during a strip chart review. The drywell vacuum breaker surveillance was implemented immediately upon discovery (initiated at 1006 hours, complete 1151 hours). The drywell vacuum breakers limit the upward forces on the drywell floor created by a higher pressure in the suppression chamber than in the drywell. When a safety relief valve lifts, discharging steam to the suppression pool, energy is added to the suppression chamber. The drywell vacuum breakers are required to be demonstrated operable in preparation for an extended safety relief valve lift or pressure control using safety relief valves for an extended period. in these cases the drywell vacuum breakers may be required to open. In this event, the lifting of two safety relief valves for 30 seconds had a negligible effect on the drywell/suppression chamber differential pressure. The time between the lifting of the safety relief valves and satisfactory performance of the drywell vacuum breaker operability test did not affect the ability of the drywell,

suppression chamber, or vacuum breakers to perform their safety function.

This condition had no effect on the safe shutdown of the plant or the health and safety of the public or plant workers.

During implementation of Emergency Operating Procedures, RPS jumpers were installed bypassing all but manual scram functions. Neither RPS trip system was placed in the trip condition nor was the reactor mode switch locked in "SHUTDOWN" as required by Technical Specification sections 3.3.1. ACTION statement b. and Table 3.3.1-1 ACTION statement 2. Using N2-EOP-6 attachment 14, operators had defeated all RPS interlocks except for the manual scram function for a period of approximately one and one half hours. This action was required in order to permit resetting the scram signal, allowing the scram discharge volume to drain, and subsequently allowing additional scrams to effect control rod insertion had it been required.

This action is directed by NMP2 EOP's and is consistent with the Boiling Water Reactor Owners' Group Emergency Program Guidelines, BWROG-EPG

Revision 4 and is specifically recognized in the NRC Safety Evaluation for BWROG-EPG Revision 4, and in NMP2 plant specific Safety Evaluation (SER 90-145 attachment 4, event 15.8).

Overview

Based on evaluation of this transient against the Updated Safety Analysis Report (USAR) transient analysis, the following conclusions were made:

o Reactor pressure rise as shown on both PAM recorders is much less severe than the pressure rise shown on Figure 15.2.1 of the USAR (Generator Load Rejection with bypass) 1070 psig vs. 1150 psig.

o Reactor water level as shown on both PAM recorders is slightly lower than the USAR, however, this discrepancy was due to all feedwater pumps tripping during the transient.

o Neutron flux was not recorded; however, the assumptions made in the USAR which influence the neutron flux spike such as pressure rise, scram speed and void fraction are all more severe than actual conditions. In addition, Instrument Surveillance Procedure N2-ISP-NMS-W@007, "APRM Functional Test", was performed on August 14, 1991, verifying proper operation of APRM flux scrams.

o Based on personnel interviews and review of as-found conditions, it can be concluded that all systems which are designed to mitigate the severity of this type of event (i.e., EOC-RPT, Turbine Bypass Valves, SRVs, and ARI) functioned as required.

Based on the above items, it can be concluded that the results of this transient were within the bounds of the current transient analysis and at no time was the health and safety of the general public or plant personnel at risk.

III. ANALYSIS OF EVENT (cont.)

USAR Section 7.4 indicates that instrumentation and controls of the following systems can be used to achieve safe shutdown:

o Reactor Core isolation Cooling (ICS)

o Standby Liquid Control System (SLS)

o Residual Heat Removal (Shutdown Cooling Mode of RHR)

o Remote Shutdown System (RSS)

The sources which supply power to the safe shutdown systems listed above originate from onsite AC/DC safety related systems. Therefore, the loss of normal UPS's (2VBB-UPS1A,1B,1C,1D,1G) and failure of the "B" Phase main output transformer at no time adversely affected the safe shutdown capability of NMP2.

The duration of the event from the reactor scram until exiting the Emergency Action Procedure EAP-2 (termination of the Site Area Emergency) was 13 hours 55 minutes.

IV. CORRECTIVE ACTIONS

The immediate corrective actions taken were: normal operator response to the turbine trip and reactor scram; identifying the cause for the loss of Control Room indication and annunciation; restoring power to the failed UPS's; and identifying the cause of the turbine trip and reactor scram.

Follow-up corrective actions include:

1. The spare main transformer was connected to the "B" phase and pre-operational testing was completed.

2. The failed "B" phase main transformer has been disconnected and removed from its pedestal. The transformer has been shipped offsite for failure analysis, which has been completed, and repair is in progress.

3. An indepth oil analysis and inspection of the remaining three transformers was performed without finding any problems. Oil samples over the last year have also been closely monitored for any abnormalities.

4. The oil in the three remaining transformers was reclaimed during the second refueling outage. This process purifies the oil by removing particulates, moisture, and gases.

IV. CORRECTIVE ACTIONS (cont.)

5. The logic power supply for 2VBB-UPS1A through 1D and 1G has been modified to be inverter preferred with the maintenance supply as a back-up.

6. All the UPS internal batteries were replaced before returning the plant to service after the event.

7. An evaluation was performed on other plant hardware that utilizes internal batteries. It was concluded that no control functions are dependent on any of these internal batteries.

8. Changes have been incorporated in the vendor manual to address the identified UPS design deficiencies.

9. During the second refueling outage, the logic power supplies for 2VBB-UPS 1A, 1B, and 1G were replaced with redundant units that require no internal battery backup.

10. In the fall of 1992, per the schedule in plant modification 89-042, 2VBB-UPS 1C and 1D will be completely replaced. The replacement UPSs do not use internal logic supply batteries.

11. Operations Support personnel have changed Operating Procedure N2-OP-37, "Reactor Water Cleanup System", to re-order the steps to assure system back pressure is established prior to beginning flow rejection that could cause system depressurization.

12. Operating Procedure N2-OP-101C, "Plant Shutdown," has been changed to address checking for SRV actuation following a plant automatic shutdown and direction is given to perform the vacuum breaker surveillance if required.

13. The issue of Licensing basis versus EOP basis for actions such as alternate control rod insertions is presently being addressed by the Boiling Water Reactor Owners' Group. Niagara Mohawk is closely following the issue and will adjust EOPs and other procedures as necessary to comply with the results of the evaluation.

V. ADDITIONAL INFORMATION

A. Failed components:

Component description - "B" phase Main Generator Step-up output transformer

Ratings - 408MVA, 65 degree Celsius rise,
FOA-1 phase - 60 Hz
Manufacturer - McGraw Edison
Mark number - 2MTX-XM1B
Serial number - C-06607-5-2
Niagara Mohawk drawing - EE-N01A
Niagara Mohawk spec - EO11A
Component description - Uninterruptible Power Supply
Ratings - 75KVA, 60KW
Manufacturer - Exide Electronics Corporation
Mark Number - 2VBB-UPS1A, 1B, 1C, 1D and 1G
Model Number - Mark II
Niagara Mohawk drawing - EE-001BH
Niagara Mohawk spec - EO35A

B. Previous similar events: none

C. Identification of components referred to in this LER:

Table omitted.

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V. ADDITIONAL INFORMATION (cont.)

Table omitted.

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Figure "Nine Mile Unit 2, Simplified Electrical Drawing" omitted.

TEXT PAGE 22 OF 23

Figure "Nine Mile Point Unit 2, Uninterruptible, Typical Series 1 (1A, 1B, 1C, 1D, 1G)" omitted.

TEXT PAGE 23 OF 23

Figure "Nine Mile Point Unit 2, Reactor Pressure and Water Level vs Time" omitted.

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